UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2014

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-36175

MIDCOAST ENERGY PARTNERS, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**61-1714064**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

1100 Louisiana
Suite 3300
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 821-2000
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☐	Accelerated Filer ☐
Non-Accelerated Filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The registrant had 22,610,056 Class A common units outstanding as of May 1, 2014.

MIDCOAST ENERGY PARTNERS, L.P.

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In this report, unless the context otherwise requires, references to "the Predecessor," "we," "our," "us," or like terms, when used in a historical context (periods prior to November 13, 2013), refer to Midcoast Operating, L.P and its subsidiaries. References in this report to "Midcoast Energy Partners," "the Partnership," "MEP," "we," "our," "us," or like terms used in the present tense or prospectively (starting November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries. We refer to our general partner, Midcoast Holdings, L.L.C., as our "General Partner" and refer to Enbridge Energy Partners, L.P. and its subsidiaries, other than us, as "Enbridge Energy Partners," or "EEP." References to "Enbridge" refer collectively to Enbridge, Inc. and its subsidiaries other than us, our subsidiaries, our General Partner, EEP, its subsidiaries and its general partner. References to "Enbridge Management" refer to Enbridge Energy Management, L.L.C., the delegate of EEP's general partner that manages EEP's business and affairs. References to "Midcoast Operating" refer to Midcoast Operating, L.P. and its subsidiaries. As of March 31, 2014, we own a 39% controlling interest in Midcoast Operating, and EEP owns a 61% non-controlling interest in Midcoast Operating. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP's 61% non-controlling interest in Midcoast Operating.

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q speaks only as of the date on which it is made, and we undertake no obligation to publicly update any forward-looking statement. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) changes in the demand for or the supply of, forecast data for, and price trends related to natural gas, natural gas liquids, or NGLs, and crude oil; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline and gathering systems, as well as other processing and treating plants; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to whom we sell products; (5) hazards and operating risks that may not be covered fully by insurance; (6) changes in or challenges to our rates; and (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance.

For additional factors that may affect results, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, which is available to the public over the Internet at the United States Securities and Exchange Commission's, or the SEC's, website (www.sec.gov) and at our website (www.midcoastpartners.com).

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions, except per unit amounts)	
Operating revenues:		
Operating revenue (Note 11)	$1,589.7	$1,311.7
Operating revenue—affiliate (Notes 9 and 11)	57.2	58.6
	1,646.9	1,370.3
Operating expenses:		
Cost of natural gas and natural gas liquids (Notes 5 and 11)	1,458.5	1,158.0
Cost of natural gas and natural gas liquids—affiliate (Notes 9 and 11)	30.2	38.1
Operating and maintenance	54.6	57.1
Operating and maintenance—affiliate (Note 9)	27.1	26.3
General and administrative	1.9	—
General and administrative—affiliate (Note 9)	25.3	24.5
Depreciation and amortization (Note 6)	37.0	35.2
	1,634.6	1,339.2
Operating income	12.3	31.1
Interest expense, net (Notes 7 and 9)	3.3	—
Other income (expense)	(1.3)	0.1
Income before income tax expense	7.7	31.2
Income tax expense (Note 12)	1.0	0.5
Net income	6.7	30.7
Less: Net income attributable to noncontrolling interest	6.3	—
Net income attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ 0.4	$ 30.7
Net income attributable to limited partner ownership interest	$ 0.4	$ 11.8
Net income per limited partner unit (basic and diluted) (Note 3)	$ 0.01	$ 0.44
Weighted average limited partner units outstanding	45.2	26.7

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Net income	$6.7	$30.7
Other comprehensive income (loss), net of tax expense (benefit) of $0.0 million as of March 31, 2014 and 2013	0.2	(0.7)
Comprehensive income	$6.9	$30.0
Less: Comprehensive income attributable to:		
Noncontrolling interest	6.3	—
Other comprehensive income allocated to noncontrolling interest	0.2	—
Comprehensive income attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$0.4	$30.0

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the three month period ended March 31, 2014	2013
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 6.7	$ 30.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	37.0	35.2
Derivative fair value net (gains) losses (Note 11)	(4.6)	1.5
Inventory market price adjustments (Note 5)	1.5	0.8
Distributions from investment in joint venture (Note 9)	1.6	—
Equity loss from investment in joint venture (Note 9)	1.3	—
Other (Note 14)	1.0	(2.2)
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	3.5	(42.8)
Due from General Partner and affiliates	616.3	7.5
Accrued receivables	59.2	133.3
Inventory (Note 5)	26.2	(2.9)
Current and long-term other assets (Note 11)	(4.8)	(1.7)
Due to General Partner and affiliates	(478.3)	16.5
Accounts payable and other (Notes 4 and 11)	(42.5)	(22.6)
Environmental liabilities (Note 10)	0.2	—
Accrued purchases	(2.4)	(37.1)
Interest payable	0.5	—
Property and other taxes payable	(8.6)	(6.9)
Net cash provided by operating activities	213.8	109.3
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 6 and 14)	(55.5)	(78.0)
Changes in restricted cash (Note 9)	47.5	—
Asset acquisitions	—	(0.9)
Proceeds from the sale of net assets	—	5.0
Investment in joint venture (Note 9)	(7.3)	(36.8)
Other	—	(1.1)
Net cash used in investing activities	(15.3)	(111.8)
Cash provided by (used in) financing activities:		
Net repayments under credit facility (Note 7)	(85.0)	—
Contributions from partners (Note 8)	39.7	63.2
Distributions to partners (Note 8)	(45.1)	(60.7)
Net cash provided by (used in) financing activities	(90.4)	2.5
Net increase in cash and cash equivalents	108.1	—
Cash and cash equivalents at beginning of year	4.9	—
Cash and cash equivalents at end of period	$ 113.0	$ —

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2014	December 31, 2013
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 4)	$ 113.0	$ 4.9
Restricted cash	14.0	61.5
Receivables, trade and other, net of allowance for doubtful accounts of $0.5 million at March 31, 2014 and December 2013	29.8	50.3
Due from general partner and affiliates (Note 9)	40.4	654.8
Accrued receivables	140.0	182.2
Inventory (Note 5)	60.3	88.0
Other current assets (Note 11)	31.2	19.1
	428.7	1,060.8
Property, plant and equipment, net (Note 6)	4,102.0	4,082.3
Goodwill	226.5	226.5
Intangibles, net	251.7	255.0
Equity investment in joint venture (Note 9)	375.7	371.3
Other assets, net (Note 11)	44.9	40.5
	$5,429.5	$6,036.4
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to general partner and affiliates (Note 9)	$ 43.2	$ 534.3
Accounts payable and other (Notes 4, 10 and 11)	79.4	114.4
Accrued purchases	460.8	463.3
Property and other taxes payable (Note 12)	11.2	19.8
Interest payable	0.8	0.3
	595.4	1,132.1
Long-term debt (Note 7)	250.0	335.0
Other long-term liabilities (Note 10 and 12)	23.3	16.6
Total liabilities	868.7	1,483.7
Commitments and contingencies (Note 10)		
Partners' capital: (Note 8)		
Class A common units (22,610,056 at March 31, 2014 and December 31, 2013)	491.8	495.3
Subordinated units (22,610,056 at March 31, 2014 and December 31, 2013)	1,031.5	1,035.1
General Partner units (922,859 at March 31, 2014 and December 31, 2013)	42.0	42.2
Accumulated other comprehensive income (loss) (Note 11)	(2.9)	(3.1)
Total Midcoast Energy Partners, L.P. partners' capital	1,562.4	1,569.5
Noncontrolling interest	2,998.4	2,983.2
Total partners' capital	4,560.8	4,552.7
	$5,429.5	$6,036.4

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. ORGANIZATION AND NATURE OF OPERATIONS

Initial Public Offering

Midcoast Energy Partners, L.P., or MEP, is a limited partnership formed by Enbridge Energy Partners, L.P, or EEP, to serve as EEP's primary vehicle for owning and growing its natural gas and natural gas liquids midstream business in the United States. We own and operate a portfolio of assets engaged in the business of gathering, processing and treating natural gas, as well as the transportation and marketing of natural gas, natural gas liquids, or NGLs, crude oil and condensate. Our portfolio of natural gas and NGL pipelines, plants and related facilities are geographically concentrated in the Gulf Coast and Mid-Continent regions of the United States, primarily in Texas and Oklahoma. On November 13, 2013, MEP completed its initial public offering, or the Offering, of 18,500,000 Class A common units (2,775,000 additional Class A common units were issued pursuant to the exercise of the underwriters' over-allotment option on December 9, 2013), representing limited partner interests. Following the completion of the Offering, EEP continues to own crude oil and liquid petroleum assets and a 61% non-controlling interest in Midcoast Operating. EEP also retained a significant interest in us through its ownership of our general partner, which owns all of our General Partner units and all of our incentive distribution rights, and a 52% limited partner interest in us. The Class A common units began trading on November 7, 2013, on the New York Stock Exchange, or NYSE, under the ticker symbol MEP. We intend to pursue acquisitions of additional interests in our natural gas assets, held through Midcoast Operating, from EEP. EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time, although EEP is not legally obligated to do so. We do not know when, or if, any such additional interests will be offered to us to purchase.

Basis of Presentation

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of March 31, 2014, our results of operations for the three month periods ended March 31, 2014 and 2013 and our cash flows for the three month periods ended March 31, 2014 and 2013. We derived our consolidated statement of financial position as of December 31, 2013, from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013. Our results of operations for the three month periods ended March 31, 2014 and 2013 should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for natural gas, NGLs and crude oil, timing and completion of our construction projects, maintenance activities, the impact of forward commodity prices and differentials on derivative financial instruments that are accounted for at fair value. These unaudited interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and accompanying footnotes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Certain adjustments relating to the prior period and having a net adverse impact of approximately $0.9 million to net income were recorded in the current period. We consider these adjustments to be immaterial to the unaudited interim consolidated financial statements both individually and taken as a whole.

Our results of operations may not be comparable to our Predecessor's historical results of operations for the reasons described below:

- Our Predecessor's results of operations historically reflected 100% of the revenues and expenses relating to Midcoast Operating. We currently own a 39% controlling interest in Midcoast Operating. We currently consolidate the results of operations of Midcoast Operating and then record a 61% non-controlling interest deduction for EEP's retained interest in Midcoast Operating.
- Although the allocation methodology under which we will continue to reimburse EEP and its affiliates for the provisions of certain administrative and operational services to Midcoast Operating will not change, $25.0 million in annual amounts payable for general and administrative expenses that were paid by Midcoast Operating historically under its existing services agreements will not be payable by Midcoast Operating going forward.
- We expect to incur an additional $4.0 million of incremental annual general and administrative expenses as a result of being a separate publicly traded partnership, 100% of which will be attributable to us.
- EEP no longer provides letters of credit and parental guarantees to Midcoast Operating at no cost, and we are responsible for our proportionate share of the annual expenses attributable to a financial support agreement that Midcoast Operating entered into with EEP. During the term of the financial support agreement, when requested by Midcoast Operating, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under certain hedges and key customer natural gas and NGL purchase agreements. The annual cost that Midcoast Operating incurs under the financial support agreement, which we estimate will initially range from approximately $4.0 million to $5.0 million, is based on the cumulative average amount of letters of credit and guarantees that EEP may provide on Midcoast Operating's behalf multiplied by a 2.5% annual fee. Based on our 39% controlling interest in Midcoast Operating, the Partnership incurred $1.2 million of these annual costs for the three months ended March 31, 2014. Without such financial support from EEP, we expect that Midcoast Operating would be required to provide letters of credit, cash collateral or other financial support with respect to these agreements or similar agreements it enters into in the future.
- We incur interest expense under our revolving credit facility, Midcoast Operating's working capital credit facility and other borrowing arrangements we may enter into from time to time. Prior to our acquiring control of our Predecessor, it was a wholly owned subsidiary of EEP and, as such, did not incur any direct interest expense from third parties and only recognized intercompany interest expense to the extent such amounts were capitalized as part of its construction projects.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, we retrospectively adopted Financial Accounting Standards Board, or FASB, Accounting Standards Update No. 2013-04, which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

3. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

We allocate our net income among our General Partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income to our limited partners, our General Partner and the holders of our incentive distribution rights, or IDRs, in accordance with the terms of our partnership agreement. We also allocate any earnings in excess of distributions to our limited partners, our General Partner and the holders of the IDRs in accordance with the terms of our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and our limited partners based on their respective proportionate ownership interests in us, after taking into account distributions to be paid with respect to the IDRs, as set forth in our partnership agreement.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to Limited Partners	Percentage Distributed to General Partner
Minimum Quarterly Distribution	Up to $0.3125	98 %	2 %
First Target Distribution	> $0.3125 to $0.359375	98 %	2 %
Second Target Distribution	> $0.359375 to $0.390625	85 %	15 %
Third Target Distribution	> $0.390625 to $0.468750	75 %	25 %
Over Third Target Distribution	In excess of $0.468750	50 %	50 %

We determined basic and diluted net income per limited partner unit as follows:

	For the three month period ended March 31,	
	2014	2013 [(3)]
	(in millions, except per unit amounts)	
Net income	$ 6.7	$30.7
Less: Net income attributable to noncontrolling interest	6.3	18.7
Net income attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	0.4	12.0
Less distributions:		
Total distributed earnings to our General Partner	(0.3)	(0.1)
Total distributed earnings to our limited partners	(14.1)	(8.4)
Total distributed earnings	(14.4)	(8.5)
Underdistributed (Overdistributed) earnings	$(14.0)	$ 3.5
Weighted average limited partner units outstanding	45.2	26.7
Basic and diluted earnings per unit:		
Distributed earnings per limited partner unit [(1)]	$ 0.31	$0.31
Underdistributed (Overdistributed) earnings per limited partner unit [(2)]	(0.30)	0.13
Net income per limited partner unit (basic and diluted)	$ 0.01	$0.44

(1) Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

(2) Represents the limited partners' share (98%) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and underdistributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

(3) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% retained by EEP.

4. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $13.7 million at March 31, 2014, and $8.8 million at December 31, 2013, are included in "Accounts payable and other" on our consolidated statements of financial position. At December 31, 2013, we reclassified a book overdraft of $49.1 million to "Accounts payable and other" on our consolidated statements of financial position.

5. INVENTORY

Our inventory is comprised of the following:

	March 31, 2014	December 31, 2013
	(in millions)	
Materials and supplies	$ 0.5	$ 0.6
Crude oil inventory	11.2	12.6
Natural gas and NGL inventory	48.6	74.8
	$60.3	$88.0

The "Cost of natural gas and natural gas liquids" on our consolidated statements of income includes charges totaling $1.5 million and $0.8 million for the three month periods ended March 31, 2014 and 2013, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs to reflect the current market value.

6. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment is comprised of the following:

	March 31, 2014	December 31, 2013
	(in millions)	
Land	$ 11.2	$ 11.6
Rights-of-way	385.5	380.0
Pipelines	1,765.0	1,741.9
Pumping equipment, buildings and tanks	79.5	79.2
Compressors, meters and other operating equipment	2,024.6	1,993.2
Vehicles, office furniture and equipment	152.1	148.5
Processing and treating plants	514.6	514.4
Construction in progress	172.5	181.4
Total property, plant and equipment	5,105.0	5,050.2
Accumulated depreciation	(1,003.0)	(967.9)
Property, plant and equipment, net	$ 4,102.0	$4,082.3

7. DEBT

Credit Agreement

On November 13, 2013, in connection with the closing of the Offering, we, Midcoast Operating, and our material domestic subsidiaries, entered into a Credit Agreement, which we refer to as the Credit Agreement, by and among us, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, our material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially: (1) $90.0 million under the letter of credit facility; and (2) $75.0 million under the swing line facility. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility matures in three years, subject to four one-year requests for extensions. At March 31, 2014, we were in compliance with the terms of our financial covenants.

Loans under the Credit Agreement accrue interest at a per annum rate by reference, at our election, to the Eurodollar rate, which is equal to the LIBOR rate or a comparable or successor rate reasonably approved by the Administrative Agent, or base rate, in each case, plus an applicable margin. The applicable margin on Eurodollar (LIBOR) rate loans ranges from 1.75% to 2.75% and the applicable margin on base rate loans ranges from 0.75% to 1.75%, in each case determined based upon our total leverage ratio (as defined below) at the applicable time. At March 31, 2014, we had $250.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, MEP had net repayments of approximately $85.0 million during the three month period ended March 31, 2014, which includes gross borrowings of $1,725.0 million and gross repayments of $1,810.0 million. A letter of credit fee is payable by the borrowers equal to the applicable margin for Eurodollar (LIBOR) rate loans times the daily amount available to be drawn under outstanding letters of credit. A commitment fee is payable by us equal to an applicable margin times the daily unused amount of the lenders' commitment, which applicable margin ranges from 0.30% to 0.50% based upon our total leverage ratio at the applicable time.

Each of our domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The credit facility is unsecured but security will be provided upon occurrence of any of the following: (1) for two consecutive quarters, the Total Leverage Ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (2) uncured breach to certain terms and conditions of the Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

Additionally, our Credit Agreement contains various covenants and restrictive provisions which limit our ability and that of Midcoast Operating and their subsidiaries to incur certain liens or permit them to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests during the continuance of a default, incur or guarantee additional debt, repay subordinated debt prior to maturity, make certain investments and acquisitions, alter their lines of business, enter into certain types of transactions with affiliates and enter into agreements that restrict their ability to perform certain obligations under the Credit Agreement or to make payments to a borrower or any of their material subsidiaries.

Our Credit Agreement also requires compliance with two financial covenants. We are not permitted to allow our ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. We must also maintain (on a consolidated basis), as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00.

These covenants are subject to exceptions and qualifications set forth in the Credit Agreement. At such time as we obtain an investment grade rating from either Moody's or S&P, certain covenants under the Credit Agreement will no longer be applicable to either the borrowers or the guarantors, or in some instances, any of them (including, but not limited to, the obligation to provide security in certain circumstances, certain restrictions on liens, investments and debt, and restrictions on dispositions).

Working Capital Credit Facility

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a $250.0 million working capital credit facility with EEP as the lender. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility are scheduled to mature in 2017 and accrue interest at a per annum rate of LIBOR, plus 2.5%. EEP's commitment to lend pursuant to the working capital credit facility will end on the earlier of the facility's maturity date (by acceleration or otherwise) and the date on which EEP owns less than 20% of the outstanding limited partner interests in Midcoast Operating. If EEP's commitment to lend has terminated before the facility has matured (by acceleration or otherwise), then the aggregate amount of all outstanding borrowings under the facility will automatically convert to a term loan that will bear interest at

LIBOR (calculated as of the conversion date) plus 2.5%. Midcoast Operating has agreed to pay a commitment fee on the unused commitment at a per annum rate of 0.4250%, payable each fiscal quarter.

The working capital credit facility also provides that, if the Credit Agreement is secured, the working capital credit facility also will be secured to the same extent on a second lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the working capital credit facility and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Financial Support Agreement

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP will provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party. Under the Financial Support Agreement, EEP's support of Midcoast Operating's and its wholly owned subsidiaries' obligations will terminate on the earlier to occur of (1) the fourth anniversary of the closing of the Offering and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in the Partnership), less than 20% of the total outstanding limited partner interest in Midcoast Operating.

The annual costs that Midcoast Operating initially estimates that it will incur under the Financial Support Agreement range from approximately $4.0 million to $5.0 million and are based on the cumulative average amount of letters of credit and guarantees that EEP will provide on Midcoast Operating's and its wholly owned subsidiaries' behalf multiplied by a 2.5% annual fee. The cumulative average amount of letters of credit and guarantees will be calculated (1) with respect to letters of credit, by reference to the aggregate face value, in U.S. dollars, of letters of credit outstanding at the close of business on any business day, after taking into account any changes in such amount since the close of business on the immediately preceding business day, and (2) with respect to guarantees, by reference to the net realizable financial obligation of Midcoast Operating and its wholly owned subsidiaries under the applicable contracts, in each case after taking into account market fluctuations in commodity prices, any related EEP letters of credit and any increases or decreases underlying each guarantee. The "net realizable financial obligation" is (1) in the case of outstanding commodity derivative contracts, the amount required to terminate or discharge each such contract based upon current market prices of the relevant commodity and (2) in the case of natural gas and NGL purchase agreements, the outstanding amount owed for product received that would be recorded as a liability under U.S. GAAP, in each case, net of any amounts owed to Midcoast Operating under any agreements with counterparties that have received guarantees from EEP. Based on the Partnership's 39% controlling interest in Midcoast Operating, the Partnership incurred $1.2 million of these annual costs for the three months ending March 31, 2014, which is included in "Operating and maintenance" on our consolidated statements of income.

The Financial Support Agreement also provides that if the Credit Agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the Financial Support Agreement and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Certain Available Credit

At March 31, 2014, we could borrow approximately $850.0 million under the terms of our Credit Agreement and the working capital credit facility, determined as follows:

	(in millions)
Total credit available under Credit Agreement	$850.0
Total credit available under working capital credit facility	250.0
Less: Amounts outstanding under Credit Agreement	250.0
Total amount we could borrow at March 31, 2014	$850.0

Fair Value of Debt Obligations

The carrying amount of our borrowings under our Credit Agreement approximates the fair value at March 31, 2014 and December 31, 2013, respectively, due to the short-term nature and frequent repricing of this obligations. The fair value of our outstanding borrowings under our Credit Agreement is included with our long-term debt obligations since we have the ability to refinance the amounts on a long-term basis. The approximate fair value of our long-term debt obligation is determined using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding. The fair value of our long-term debt obligation is categorized as Level 2 within the fair value hierarchy.

8. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Midcoast Holdings, L.L.C, our General Partner, during the three month period ended March 31, 2014.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Distributed
			(in millions, except per unit amounts)	
January 29, 2014	February 7, 2014	February 14, 2014	$ 0.16644	$7.7

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interest in our consolidated subsidiary for the three month periods ended March 31, 2014 and 2013.

	For the three month period ended March 31, 2014	2013
	(in millions)	
Class A common units:		
Beginning balance	$ 495.3	$ —
Net income	0.2	—
Distributions	(3.7)	—
Ending balance	$ 491.8	$ —
Subordinated units:		
Beginning balance	$1,035.1	$ —
Net income	0.2	—
Distributions	(3.8)	—
Ending balance	$1,031.5	$ —
General Partner units:		
Beginning balance	$ 42.2	$ —
Distributions	(0.2)	—
Ending balance	$ 42.0	$ —
Limited Partner: (1)		
Beginning balance	$ —	$4,707.1
Capital contribution	—	66.1
Net income	—	30.7
Distributions	—	(60.7)
Ending balance	$ —	$4,743.2
Accumulated other comprehensive income (loss)		
Beginning balance	$ (3.1)	$ 7.1
Net realized income on changes in fair value of derivative financial instruments reclassified to earnings	6.5	(1.5)
Unrealized net income (loss) on derivative financial instruments	(6.3)	0.8
Ending balance	$ (2.9)	$ 6.4
Noncontrolling interest		
Beginning balance	$2,983.2	$ —
Capital contributions	46.1	—
Comprehensive income:		
Net income	6.3	—
Other comprehensive income, net of tax	0.2	—
Distributions to noncontrolling interest	(37.4)	—
Ending balance	$2,998.4	$ —
Total partners' capital at end of period	$4,560.8	$4,749.6

(1) These amounts represent the changes in the capital account for the three month period ended March 31, 2013 of the former limited partner of Midcoast Operating, our predecessor for accounting purposes. These changes are not comparable to the Partnership's limited partner interests, and thus, are shown here separately.

9. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

We do not directly employ any of the individuals responsible for managing or operating our business. We entered into an intercorporate services agreement with EEP pursuant to which we agreed upon certain aspects of our relationship with EEP, including the provision by EEP or its affiliates to us of certain administrative services and employees, our agreement to reimburse EEP or its affiliates for the cost of such services and employees and certain other matters.

Intercorporate Services Agreement

On November 13, 2013, in connection with the closing of the Offering, the Partnership entered into an Intercorporate Service Agreement with EEP, pursuant to which EEP provides the Partnership with the shared services, such as management and accounting.

Under the Intercorporate Services Agreement, the Partnership reimburses EEP and its affiliates for the costs and expenses incurred in providing such services to the Partnership. The allocation methodology under which the Partnership reimburses EEP and its affiliates for the provision of general administrative and operational services to Midcoast Operating does not differ from what Midcoast Operating was allocated historically under its prior services agreements with Enbridge and certain of its affiliates that were in effect prior to the Intercorporate Services Agreement. However, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually. For the three month period ending March 31, 2014, we recognized $6.4 million as a reduction to “Due to general partner and affiliates” with the offset to “Noncontrolling interest” in our consolidated statements of financial position related to this reduction in amounts payable to EEP for general and administrative expenses.

The total amount incurred by us, through EEP for services received pursuant to the general and administrative services agreement for the three month periods ended March 31, 2014 and 2013 were $52.4 million and $50.8 million, respectively. These amounts were settled through “Cash” and “Contributions from partners” as reflected on our consolidated statements of cash flows for the three month periods ended March 31, 2014 and 2013 respectively. The following table presents the affiliate amounts reflected in our consolidated statements of income by category as follows:

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Operating and maintenance—affiliate	$27.1	$26.3
General and administrative—affiliate	25.3	24.5
Total	$52.4	$50.8

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of $0.9 million and $6.8 million as of March 31, 2014 and December 31, 2013, respectively, that we recorded as additions to “Property, plant and equipment, net” on our consolidated statements of financial position.

Affiliate Revenues and Purchases

We purchase natural gas, NGLs and crude oil from third parties, which subsequently generate operating revenues from sales to Enbridge and its affiliates. The sales to Enbridge and its affiliates are presented in “Operating revenue—affiliate” on our consolidated statements of income. These transactions are entered into at the market price on the date of sale. Included in our results for the three month periods ended March 31, 2014 and 2013 are operating revenues from sales to Enbridge and its affiliates of $57.2 million and $58.6 million, respectively.

We also purchase natural gas, NGLs and crude oil from Enbridge and its affiliates for sale to third parties at market prices on the date of purchase. The purchases of natural gas, NGLs and crude oil from Enbridge and its affiliates are presented in "Cost of natural gas and natural gas liquids—affiliate" on our consolidated statements of income. Included in our results for the three month periods ended March 31, 2014 and 2013 are costs for natural gas, NGLs and crude oil purchases from Enbridge and its affiliates of $30.2 million and $38.1 million, respectively. Routine purchases and sales with affiliates are settled monthly through MEP's centralized treasury function at terms that are consistent with third-party transactions for the three month period ended March 31, 2014. For the three month period ended March 31, 2013, our Predecessor's routine purchases and sales with affiliates were settled monthly through EEP's centralized treasury function at terms that were consistent with third-party transactions. Routine purchases and sales with affiliates that have not yet been settled are included in "Due from general partner and affiliates" and "Due to general partner and affiliates" on our consolidated statements of financial position.

Related Party Transactions with Joint Venture

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together are constructing a 580 mile NGL intrastate transportation pipeline and a related NGL gathering system that was placed into service in the fourth quarter of 2013. Our equity investment in the Texas Express NGL system at March 31, 2014 and December 31, 2013 was $375.7 million and $371.3 million, respectively, which is included on our consolidated statements of financial position in "Equity investment in joint venture." For the three month period ending March 31, 2014 we recognized a $1.3 million equity loss in "Other income (expense)" on our consolidated statement of income related to our investment in the system.

Our logistics and marketing business has made commitments to transport up to 120,000 barrels per day, or bpd, of NGLs on the Texas Express NGL system from 2014 to 2023.

Partners' Capital Transactions

Cash distributions totaling $37.4 million were paid on February 14, 2014 to EEP by Midcoast Operating as follows: (i) in the amount of $22.3 million for that portion of the three month period ending December 31, 2013 prior to the Offering, and (ii) in the amount of $15.1 million for the period from the completion of the Offering through December 31, 2013. In addition, on February 14, 2014, cash distributions totaling $4.1 million were paid to EEP and Midcoast Holdings by the Partnership for the period from the completion of the Offering through December 31, 2013. These amounts were settled through "Distributions to partners" as reflected on our consolidated statements of cash flows.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013 and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of those of our subsidiaries and other subsidiaries of EEP that are parties thereto up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement. EEP and, as of December 2, 2013, MEP, each act in an administrative capacity as collection agent on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. EEP and MEP have no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative—affiliate" expense in our consolidated statements of income. For the three month period ended March 31, 2014, the loss stemming from the discount on the receivables sold was $0.3 million. For the three period ended March 31, 2014, we derecognized and sold $976.3 million of accrued receivables to the Enbridge subsidiary. For the three month period ended March 31, 2014, the cash proceeds were $976.0 million which was remitted to the buyer through our centralized treasury system. As of March 31, 2014, $322.4 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of March 31, 2014, we have $14.0 million included in "Restricted cash" on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary.

Allocated Interest

Historically, EEP incurred borrowing cost on behalf of our Predecessor, which we recognized to the extent we were able to capitalize such costs to our construction related projects. The interest cost we incurred was directly offset by the amount of interest we capitalized on outstanding construction projects.

Our interest cost of the three months ended March 31, 2013 is detailed below.

	For the three month period ended March 31,
	2013
	(unaudited; in millions)
Interest cost incurred	$ 5.6
Interest capitalized	5.6
Interest expense, net	$—
Interest cost paid	$ 5.6

Derivative Transactions

Our Predecessor has historically had related party derivative transactions executed on behalf of EEP that were contracted through our Predecessor prior to the Offering and were allocated to EEP. These transactions were contracted to hedge the forward price of EEP's crude oil length inherent to the operation of pipelines and to hedge EEP's interest payments of variable rate debt obligations. Subsequent to the Offering, these transactions were re-contracted through EEP and are no longer allocated from our Predecessor. These historical transactions are included as part of Note 11. *Derivative Financial Instruments and Hedging Activities.*

10. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to the operating activities of our gathering, processing and transportation and logistics and marketing businesses, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or otherwise, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our gathering, processing and transportation and logistics and marketing businesses. We continue to voluntarily monitor past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations. As of March 31, 2014 and December 31, 2013, we did not record any environmental liabilities.

Legal and Regulatory Proceedings

We are a participant in a number of legal proceedings arising in the ordinary course of business. Some of these proceedings are not covered, in whole or in part, by insurance. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial position, results of operations or cash flows. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

11. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with commodity price risks through 2017 in accordance with our risk management policies.

Accounting Treatment

Effective January 1, 2014, the Partnership elected to prospectively change its presentation of derivative assets and liabilities from a net basis to a gross basis in the Consolidated Statements of Financial Position. This change was adopted to provide more granular information related to the future economic benefits available to, and obligations of, the Partnership in our Consolidated Statements of Financial Position. This change had no impact to the Consolidated Statements of Income, Net income (loss) per limited partner unit, or Partners' capital.

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply a mid-market pricing convention, which we refer to as the market approach, to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimates of fair value.

In accordance with the applicable authoritative accounting guidance, if a derivative financial instrument does not qualify as a cash flow hedge, or is not designated as a cash flow hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in "Cost of natural gas and natural gas liquids" or "Operating revenue" for our commodity-based derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in "Accumulated other comprehensive income," also referred to as AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement until the underlying transaction occurs. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in "cost of natural gas and natural gas liquids" for commodity hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have derivative financial instruments associated with our commodity activities where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value included in "Cost of natural gas and natural gas liquids" or "Operating revenue" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to volatility in our earnings and in our cash flows upon settlement:

Commodity Price Exposures:

- **Transportation**—In our logistics and marketing business, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.

- **Storage**—In our logistics and marketing business, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the natural gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas or NGLs are recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas and NGL storage activities can increase volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **Optional Natural Gas Processing Volumes**—In our gathering, processing and transportation business, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL Forward Contracts**—In our logistics and marketing business, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. A sub-group of physical NGL sales contracts qualify for the normal purchases and normal sales, or NPNS, scope exception. All other forward contracts are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.
- **Natural Gas Forward Contracts—**In our logistics and marketing business, we use forward contracts to sell natural gas to our customers. Certain physical natural gas contracts with terms allowing for economic net settlement are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Crude Forward Contracts**—In our logistics and marketing business, we use forward contracts to fix the price of crude we purchase and store in inventory and to fix the price of crude that we sell from inventory. A sub-group of physical crude contracts with terms allowing for economic net settlement do not qualify for the NPNS, scope exception and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in crude prices until the forward contracts are settled.
- **Condensate**, **Natural Gas and NGL Options**—In our gathering, processing and transportation business, we use options to hedge the forecasted commodity exposure of our condensate, NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to volatility due to movements in the prices of condensate, NGLs and natural gas until the underlying long-term transactions are settled.

In all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical cost or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	March 31, 2014	December 31, 2013
	(in millions)	
Other current assets	$ 24.2	$ 10.3
Other assets, net	14.8	10.3
Accounts payable and other	(28.5)	(21.1)
Other long-term liabilities	(7.0)	(0.9)
	$ 3.5	$ (1.4)

The changes in the assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $0.3 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the three month period ended March 31, 2014, unrealized commodity hedge losses of $0.1 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $8.2 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at March 31, 2014, will be reclassified from AOCI to earnings during the next 12 months.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	March 31, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$—	$ 0.2
AA	(0.5)	(2.1)
A	2.0	(1.1)
Lower than A	2.0	1.6
	$ 3.5	$(1.4)

[1] As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has increased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also increased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. As of March 31, 2014 and December 31, 2013, we were not holding any cash collateral on our asset exposures. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At March 31, 2014 and December 31, 2013, we had credit concentrations in the following industry sectors, as presented below:

	March 31, 2014	December 31, 2013
	(in millions)	
United States financial institutions and investment banking entities	$ 2.3	$ 2.4
Non-United States financial institutions	0.8	0.1
Integrated oil companies	(0.5)	(1.6)
Other	0.9	(2.3)
	$ 3.5	$(1.4)

Gross derivative balances are presented below before the effects of collateral received or posted and without the effects of master netting arrangements. Both our assets and liabilities are adjusted for non-performance risk, which is statistically derived. This credit valuation adjustment model considers existing derivative asset and liability balances in conjunction with contractual netting and collateral arrangements, current market data such as credit default swap rates and bond spreads and probability of default assumptions to quantify an adjustment to fair value. For credit modeling purposes, collateral received is included in the calculation of our assets, while any collateral posted is excluded from the calculation of the credit adjustment. Our credit exposure for these over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Financial Position Location	Asset Derivatives Fair Value at March 31, 2014	Asset Derivatives Fair Value at December 31, 2013	Liability Derivatives Fair Value at March 31, 2014	Liability Derivatives Fair Value at December 31, 2013
		(in millions)			
Derivatives designated as hedging instruments [(1)]					
Commodity contracts	Other current assets	$ 3.2	$ 2.0	$ —	$ (0.6)
Commodity contracts	Other assets	2.8	3.5	—	(0.5)
Commodity contracts	Accounts payable and other	—	1.9	(10.7)	(12.7)
Commodity contracts	Other long-term liabilities	—	0.6	(0.9)	(1.4)
		6.0	8.0	(11.6)	(15.2)
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	21.0	9.0	—	(0.1)
Commodity contracts	Other assets	12.0	10.7	—	(3.4)
Commodity contracts	Accounts payable and other	—	5.4	(17.8)	(15.7)
Commodity contracts	Other long-term liabilities	—	—	(6.1)	(0.1)
		33.0	25.1	(23.9)	(19.3)
Total derivative instruments		$39.0	$33.1	$(35.5)	$(34.5)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [(1)]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [(1)]
		(in millions)			
For the three month period ended March 31, 2014					
Commodity contracts	$(0.1)	Cost of natural gas and natural gas liquids	$(6.5)	Cost of natural gas and natural gas liquids	$1.7
Total	$(0.1)		$(6.5)		$1.7
For the three month period ended March 31, 2013					
Commodity contracts	$(1.6)	Cost of natural gas and natural gas liquids	$ 1.5	Cost of natural gas and natural gas liquids	$0.5
Total	$(1.6)		$ 1.5		$0.5

(1) Includes only the ineffective portion of derivatives that are designated as hedging instruments and does not include net gains or losses associated with derivatives that do not qualify for hedge accounting treatment.

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges
	(in millions)
Balance at December 31, 2013	$(3.1)
Other Comprehensive Income before reclassifications [1]	(2.4)
Amounts reclassified from AOCI [2] [3]	2.6
Tax benefit (expense)	0.0
Net other comprehensive income (loss)	$ 0.2
Balance at March 31, 2014	$(2.9)

(1) Excludes NCI loss of $3.7 million reclassified from AOCI at March 31, 2014.

(2) Excludes NCI gain of $3.9 million reclassified from AOCI at March 31, 2014.

(3) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

Reclassifications from Accumulated Other Comprehensive Income

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Losses (gains) on cash flow hedges:		
Commodity Contracts [1] [2]	$2.6	$(1.5)
Total Reclassifications from AOCI	$2.6	$(1.5)

(1) Loss (gain) reported within "Cost of natural gas and natural gas liquids" in the consolidated statements of income.

(2) Excludes NCI gain of $3.9 million reclassified from AOCI at March 31, 2014.

Effect of Derivative Instruments on Consolidated Statements of Income

		For the three month period ended March 31,	
		2014	2013 [4]
Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings [1]	Amount of Gain or (Loss) Recognized in Earnings [2]	
		(unaudited; in millions)	
Commodity contracts	Cost of natural gas and natural gas liquids [3]	$(6.4)	$(2.4)
Commodity contracts	Operating revenue	0.8	—
Total		$(5.6)	$(2.4)

(1) Does not include settlements associated with derivative instruments that settle through physical delivery.

(2) Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.

(3) Includes settlements losses of $8.5 million and $0.4 million for the three month periods ended March 31, 2014 and March 31, 2013, respectively.

(4) Includes both affiliate and third party transactions.

We record the fair market value of our derivative financial and physical instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a gross basis. However, the terms of the ISDA®, which governs our financial contracts and our other master netting agreements, allow the parties to elect in respect of all transactions under the agreement, in the event of a default and upon notice to the defaulting party, for the non-defaulting party to set-off all settlement payments, collateral held and any other obligations (whether or not then due), which the non-defaulting party owes to the defaulting party. The effect of the rights of set-off are outlined below.

Offsetting of Financial Assets and Derivative Assets

	As of March 31, 2014		
	Gross Amount of Assets Presented in the Statement of Financial Position	Amount Not Offset in the Statement of Financial Position	Net Amount
	(unaudited; in millions)		
Description:			
Derivatives	$39.0	$(18.2)	$20.8
Total	$39.0	$(18.2)	$20.8

Offsetting of Financial Liabilities and Derivative Liabilities

	As of March 31, 2014		
	Gross Amount of Liabilities Presented in the Statement of Financial Position	Amount Not Offset in the Statement of Financial Position	Net Amount
	(unaudited; in millions)		
Description:			
Derivatives	$(35.5)	$18.2	$(17.3)
Total	$(35.5)	$18.2	$(17.3)

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2014 and December 31, 2013. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument, as Level 2. This category includes both over-the-counter, or OTC, transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (1) quoted prices for assets and liabilities; (2) time value; (3) volatility factors; and (4) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

	March 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Commodity contracts:								
Financial	$—	$(3.9)	$(3.4)	$(7.3)	$—	$(3.4)	$(6.9)	$(10.3)
Physical	—	—	3.6	3.6	—	—	0.5	0.5
Commodity options	—	—	7.2	7.2	—	—	8.4	8.4
Total	$—	$(3.9)	$ 7.4	$ 3.5	$—	$(3.4)	$ 2.0	$ (1.4)

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs and Crude Oil) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at March 31, 2014	Valuation Technique	Unobservable Input	Range (1) Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$(0.3)	Market Approach	Forward Gas Price	3.88	4.68	4.42	MMBtu
NGLs	$(3.1)	Market Approach	Forward NGL Price	1.01	2.18	1.35	Gal
Commodity Contracts - Physical							
Natural Gas	$ 2.3	Market Approach	Forward Gas Price	3.34	5.17	4.25	MMBtu
Crude Oil	$(1.2)	Market Approach	Forward Crude Price	87.93	106.27	100.05	Bbl
NGLs	$ 2.5	Market Approach	Forward NGL Price	0.01	2.31	1.11	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 7.2	Option Model	Option Volatility	15%	77%	34%	
Total Fair Value	$ 7.4						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas, dollars per Gallon, or Gal, for NGLs and dollars per barrel, or Bbl, for Crude Oil.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013 (2)	Valuation Technique	Unobservable Input	Range (1) Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$—	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	$(6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	$(0.5)	Market Approach	Forward Crude Price	86.37	103.04	97.24	Bbl
NGLs	$(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 2.0						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.
(2) Fair values include credit valuation adjustments of approximately $0.1 million of gains.

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2014 to March 31, 2014. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
		(in millions)		
Beginning balance as of January 1, 2014	$(6.9)	$ 0.5	$ 8.4	$ 2.0
Transfer out of Level 3 (1)	—	—	—	—
Gains or losses:				
Included in earnings	(5.3)	1.7	(1.5)	(5.1)
Included in other comprehensive income	(1.1)	—	—	(1.1)
Purchases, issuances, sales and settlements:				
Purchases	—	—	0.2	0.2
Settlements (2)	9.9	1.4	0.1	11.4
Ending balance as of March 31, 2014	$(3.4)	$ 3.6	$ 7.2	$ 7.4
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$(1.2)	$ 1.9	$(1.1)	$ (0.4)
Amounts reported in operating revenue	$—	$ 0.8	$—	$ 0.8

(1) Our policy is to recognize transfers as of the last day of the reporting period.
(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2014 and December 31, 2013.

	At March 31, 2014						At December 31, 2013	
			Wtd. Average Price [2]		Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	872,000	$ 4.43	$ 4.28	$ 0.1	$—	$—	$ —
	NGL	653,750	$ 65.16	$ 65.99	$ 0.9	$(1.5)	$ 0.6	$ (0.4)
	Crude Oil	70,000	$100.82	$100.10	$ 0.1	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	2,443,800	$ 4.00	$ 4.39	$—	$(1.0)	$ 0.1	$ (1.0)
	NGL	1,967,500	$ 54.50	$ 56.00	$ 4.8	$(7.7)	$ 4.8	$(12.7)
	Crude Oil	858,250	$ 91.82	$ 98.09	$ 0.2	$(5.6)	$ 0.3	$ (5.4)
Receive variable/pay variable	Natural Gas	38,490,000	$ 4.38	$ 4.38	$ 0.6	$(0.4)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	5,703,122	$ 4.46	$ 4.41	$ 0.4	$(0.1)	$—	$ —
	NGL	1,073,640	$ 57.57	$ 57.25	$ 1.2	$(0.9)	$ 0.9	$ (0.9)
	Crude Oil	243,713	$ 99.24	$ 99.81	$ 0.3	$(0.4)	$—	$ —
Receive fixed/pay variable	Natural Gas	23,485,419	$ 4.33	$ 4.33	$ 0.1	$(0.1)	$—	$ —
	NGL	1,197,064	$ 55.26	$ 56.68	$ 0.1	$(1.8)	$ 0.4	$ (2.6)
	Crude Oil	333,526	$ 99.25	$100.28	$ 0.4	$(0.7)	$—	$ (0.4)
Receive variable/pay variable	Natural Gas	89,130,497	$ 4.41	$ 4.40	$ 1.8	$(0.7)	$ 0.9	$ (0.4)
	NGL	8,029,834	$ 42.91	$ 42.48	$ 5.2	$(1.7)	$ 5.8	$ (3.7)
	Crude Oil	843,189	$ 97.13	$ 98.03	$ 3.4	$(4.1)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Natural Gas	60,000	$ 4.52	$ 4.51	$—	$—	$—	$ —
	NGL	565,750	$ 51.33	$ 50.71	$ 1.4	$(1.1)	$ 1.5	$ (1.1)
	Crude Oil	350,400	$ 93.00	$ 89.89	$ 1.2	$(0.2)	$ 1.7	$ —
Receive variable/pay variable	Natural Gas	10,107,500	$ 4.32	$ 4.33	$ 0.1	$(0.1)	$ 0.1	$ —
Receive variable/pay fixed	Crude Oil	67,500	$ 92.58	$ 91.10	$ 0.1	$—	$—	$ —
Physical Contracts								
Receive fixed/pay variable	Natural Gas	3,158,951	$ 4.49	$ 4.50	$—	$—	$—	$ —
	NGL	54,760	$ 54.21	$ 52.91	$ 0.1	$—	$—	$ —
Receive variable/pay variable	Natural Gas	46,325,708	$ 4.24	$ 4.22	$ 1.2	$(0.4)	$ 0.5	$ (0.1)
	NGL	808,001	$ 71.16	$ 70.79	$ 0.4	$(0.1)	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 84.52	$ 0.7	$—	$ 0.7	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	31,192,423	$ 3.97	$ 3.97	$ 0.7	$(0.5)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	13,425,825	$ 4.17	$ 4.18	$ 0.3	$(0.4)	$—	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at March 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of gains at December 31, 2013.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at March 31, 2014 and December 31, 2013.

	At March 31, 2014						At December 31, 2013	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
						(in millions)		
Portion of option contracts maturing in 2014								
Puts (purchased) . . .	Natural Gas	3,300,000	$ 3.90	$ 4.46	$ 0.4	$—	$ 0.7	$—
	NGL	394,500	$53.04	$53.17	$ 2.3	$—	$ 2.9	$—
Calls (written)	NGL	206,250	$59.62	$54.36	$—	$(0.6)	$—	$(1.0)
Puts (written)	Natural Gas	1,729,000	$ 3.90	$ 4.49	$—	$(0.2)	$—	$(0.5)
Calls (purchased) . .	NGL	46,000	$50.40	$45.73	$ 0.2	$—	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased) . . .	Natural Gas	4,015,000	$ 3.90	$ 4.20	$ 1.9	$—	$ 1.7	$—
	NGL	1,113,250	$50.64	$53.31	$ 6.1	$—	$ 6.0	$—
	Crude Oil	456,250	$85.00	$89.50	$ 2.3	$—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.20	$—	$(0.4)	$—	$(0.3)
	NGL	292,000	$62.48	$57.59	$—	$(1.6)	$—	$(1.0)
	Crude Oil	456,250	$90.70	$89.50	$—	$(3.1)	$—	$(1.9)
Portion of option contracts maturing in 2016								
Puts (purchased) . . .	Crude Oil	91,500	$80.00	$84.30	$ 0.6	$—	$—	$—
Calls (written)	Crude Oil	91,500	$87.00	$84.30	$—	$(0.7)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at March 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

12. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the state of Texas that is based upon many but not all items included in net income.

We computed our income tax expense by applying a Texas state income tax rate to modified gross margin. Our Texas state income tax rate was 0.5% for the three month periods ended March 31, 2014 and 2013. Our income tax expense is $1.0 million and $0.5 million for the three month periods ended March 31, 2014 and 2013, respectively.

At March 31, 2014 and December 31, 2013, we have included a current income tax payable of $1.8 million and $1.0 million, respectively, in "Property and other taxes payable" on our consolidated statements of financial position. In addition, at March 31, 2014 and December 31, 2013, we have included a deferred income tax payable of $11.6 million and $11.1 million, respectively, in "Other long-term liabilities" on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

13. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker, collectively comprised of our senior management, in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We conduct our business through two distinct reporting segments:

- Gathering, Processing and Transportation; and
- Logistics and Marketing.

The following tables present certain financial information relating to our business segments and corporate activities:

	As of and for the three month period ended March 31, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate [1]	Total
	(in millions)			
Total revenue	$ 725.0	$1,473.0	$ —	$2,198.0
Less: Intersegment revenue	521.7	29.4	—	551.1
Operating revenue	203.3	1,443.6	—	1,646.9
Cost of natural gas and natural gas liquids	84.8	1,403.9	—	1,488.7
Segment gross margin	118.5	39.7	—	158.2
Operating and maintenance	64.4	17.3	—	81.7
General and administrative	24.0	3.2	—	27.2
Depreciation and amortization	35.0	2.0	—	37.0
	123.4	22.5	—	145.9
Operating income (loss)	(4.9)	17.2	—	12.3
Interest expense, net	—	—	3.3	3.3
Other expense [3]	(1.2)	—	(0.1)	(1.3)
Income (loss) before income tax expense	(6.1)	17.2	(3.4)	7.7
Income tax expense	—	—	1.0	1.0
Net income (loss)	(6.1)	17.2	(4.4)	6.7
Less: Net income attributable to:				
Noncontrolling interest	—	—	6.3	6.3
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ (6.1)	$ 17.2	$ (10.7)	$ 0.4
Total assets [2]	$4,901.7	$ 311.1	$216.7	$5,429.5
Capital expenditures (excluding acquisitions)	$ 47.8	$ 2.3	$ 5.3	$ 55.4

(1) Corporate consists of income taxes and interest expense, which are not allocated to the business segments.

(2) Totals assets for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

(3) Other income (expense) for our Gathering, Processing and Transportation segment includes our equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

	As of and for the three month period ended March 31, 2013			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate (1)	Total
	(in millions)			
Total revenue	$ 659.2	$1,223.0	$ —	$1,882.2
Less: Intersegment revenue	487.0	24.9	—	511.9
Operating revenue	172.2	1,198.1	—	1,370.3
Cost of natural gas and natural gas liquids	17.4	1,178.7	—	1,196.1
Segment gross margin	154.8	19.4	—	174.2
Operating and maintenance	64.2	19.2	—	83.4
General and administrative	21.9	2.6	—	24.5
Depreciation and amortization	33.5	1.7	—	35.2
	119.6	23.5	—	143.1
Operating income (loss)	35.2	(4.1)	—	31.1
Other income (expense)	—	—	0.1	0.1
Income (loss) before income tax expense	35.2	(4.1)	0.1	31.2
Income tax expense	—	—	0.5	0.5
Net income (loss)	$ 35.2	$ (4.1)	$ (0.4)	$ 30.7
Total assets (2)	$4,533.1	$ 843.2	$237.6	$5,613.9
Capital expenditures (excluding acquisitions)	$ 66.3	$ 4.6	$ —	$ 70.9

(1) Corporate consists of income taxes, which are not allocated to the business segments.

(2) Totals assets for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

14. SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides supplemental information for the item labeled "Other" in the "Cash provided by operating activities" section of our consolidated statements of cash flows.

	For the three month period ended March 31,	
	2014	2013
	(in millions)	
Deferred income taxes	$ 0.5	$—
Texas Express long-term inventory (line fill)	0.3	—
Loss on sale of assets	—	1.1
Allowance for interest used during construction	—	(2.8)
Amortization of hedging	—	(0.2)
Other	0.2	(0.3)
	$ 1.0	$(2.2)

In the "Cash used in investing activities" section of the consolidated statements of cash flows, we exclude changes that did not affect cash. The following is a reconciliation of additions to property, plant and equipment to total capital expenditures (excluding "Investment in joint venture"):

	For the three month period ended March 31,	
	2014	2013
	(in millions)	
Additions to property, plant and equipment	$55.5	$78.0
Decrease in construction payables	(0.1)	(7.1)
Total capital expenditures (excluding "Investment in joint venture")	$55.4	$70.9

15. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In April of 2014, FASB issued Accounting Standards Update No. 2014-08 that changes the criteria and requires expanded disclosures for reporting discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on our consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

16. SUBSEQUENT EVENTS

Distribution to Partners

On April 29, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to our partners on May 15, 2014. The distribution will be paid to unitholders of record as of May 8, 2014, of our available cash of $14.4 million at March 31, 2014, or $0.3125 per limited partner unit. We will pay $6.6 million to our public Class A common unitholders, while $7.8 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On April 29, 2014, the general partner of Midcoast Operating, acting in its capacity as the general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of May 8, 2014. Midcoast Operating will pay $15.3 million to us and $23.9 million to EEP.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 1. *Financial Statements* and in conjunction with the audited consolidated financial statements and accompanying footnotes in our Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the SEC on February 18, 2014. On November 13, 2013, we completed our initial public offering, or the Offering, of 18,500,000 Class A common units representing limited partner interests in the Partnership.

Unless the context otherwise requires, references in this report to the Predecessor, we, our, us, or like terms, when used in a historical context (periods prior to November 13, 2013), refer to Midcoast Operating. References in this report to Midcoast Energy Partners, the Partnership, MEP, we, our, us, or like terms used in the present tense or prospectively (periods beginning on or after November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries.

Items Affecting the Comparability of Our Financial Results

Our future results of operations may not be comparable to our Predecessor's historical results of operations for the reasons described below:

- Our Predecessor's results of operations historically reflected 100% of the revenues and expenses relating to Midcoast Operating. At the close of the Offering, EEP contributed to us a 39% controlling interest in Midcoast Operating. We currently consolidate the results of operations of Midcoast Operating and then initially record a 61% non-controlling interest deduction for EEP's retained interest in Midcoast Operating. Additionally, although EEP has the option to fund its pro rata share of Midcoast Operating's capital expenditures, to the extent it elects not to do so, we may elect to fund EEP's portion in exchange for additional interests in Midcoast Operating and, as a result, our interest in Midcoast Operating would increase over time.
- Although the allocation methodology under which we will continue to reimburse EEP and its affiliates for the provisions of certain administrative and operational services to Midcoast Operating will not change, $25.0 million in annual amounts payable for general and administrative expenses that were paid by Midcoast Operating historically under its existing services agreements will not be payable by Midcoast Operating going forward.
- We expect to incur an additional $4.0 million of incremental annual general and administrative expenses as a result of being a separate publicly traded partnership, 100% of which will be attributable to us.
- EEP no longer provides letters of credit and parental guarantees to Midcoast Operating at no cost and we are responsible for our proportionate share of the annual expenses attributable to a financial support agreement that Midcoast Operating entered into with EEP. During the term of the financial support agreement, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under certain legacy hedges and key customer natural gas and NGL purchase agreements. The annual cost that Midcoast Operating incurs under the financial support agreement, which we estimate will initially range from approximately $4.0 million to $5.0 million, is based on the cumulative average amount of letters of credit and guarantees that EEP may provide on Midcoast Operating's behalf multiplied by a 2.5% annual fee. Based on our 39% controlling interest in Midcoast Operating, we estimate that our proportionate share of these annual expenses will initially range from approximately $1.6 million to $2.0 million. EEP has historically provided such financial support to Midcoast Operating at no cost. Without such financial support from EEP, we expect that Midcoast Operating would be required to provide letters of credit, cash collateral or other financial support with respect to these agreements or similar agreements it enters into in the future. For more information regarding our financial support agreement and the calculation of this annual fee, please read "Liquidity and Capital Resources—Financial Support Agreement."
- We incur interest expense under our revolving credit facility, Midcoast Operating's working capital credit facility and other borrowing arrangements we may enter into from time to time. Prior to our acquiring control of our Predecessor, it was a wholly owned subsidiary of EEP and, as such, did not incur any direct interest expense from third parties and only recognized intercompany interest expense to the extent such amounts were capitalized as part of its construction projects.

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through two business segments: Gathering, Processing and Transportation; and Logistics and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the three month periods ended March 31, 2014 and 2013.

	For the three month period ended March 31,	
	2014	**2013**
	(unaudited; in millions)	
Operating income (loss)		
Gathering, Processing and Transportation	$ (4.9)	$35.2
Logistics and Marketing	17.2	(4.1)
Corporate	—	—
Total operating income	12.3	31.1
Interest expense	3.3	—
Other income (expense)	(1.3)	0.1
Income tax expense	1.0	0.5
Net income	$ 6.7	$30.7

Contractual arrangements in our Gathering, Processing and Transportation segment and our Logistics and Marketing segment expose us to market risks associated with changes in commodity prices where we receive NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices, which can be significant during periods of price volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Gathering, Processing and Transportation

The operating income of our Gathering, Processing and Transportation segment for the three month period ended March 31, 2014 decreased $40.1 million, when compared to the same period in 2013, primarily due to the following:

- Decreased operating income of approximately $21.0 million for the three month period ended March 31, 2014, primarily due to reduced average daily volumes on our major systems primarily attributable to reduced and delayed drilling activity in the Anadarko and East Texas regions, respectively, in the first quarter when compared to the same period in 2013;
- Decreased operating revenue less the cost of natural gas derived from keep-whole processing earnings of $7.5 million when compared to the same period in 2013, due to a decline in total NGL production primarily caused by the Avinger plant shutdown from early January until mid-February of 2014;
- Decreased operating income of approximately $3.0 million for the three month period ended March 31, 2014, primarily due to the impact of sustained freezing temperatures which significantly disrupted producer well head production levels and our pipeline operations compared to the same period in 2013;
- Decreased operating income of $1.4 million for the three month period ended March 31, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same period in 2013;

- Decreased operating income of $1.1 million for the three month period ended March 31, 2014 in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment, when compared to the same period in 2013;
- Increased general and administrative costs of $2.1 million for the three month period ended March 31, 2014, as compared with the same period in 2013, due to increased workforce costs; and
- Increased depreciation and amortization expense of $1.5 million for the three month period ended March 31, 2014, as compared with the same period in 2013, due to additional assets that were put in service.

Logistics and Marketing

The operating income of our Logistics and Marketing segment for the three month period ended March 31, 2014 increased $21.3 million when compared to the same period in 2013, primarily due to the following:

- Increased operating income of approximately $10.0 million for the three month period ended March 31, 2014 when compared with the same period in 2013, primarily due to additional opportunities attributable to pricing differences between market centers;
- Increased operating income of approximately $7.2 million for the three month period ended March 31, 2014 when compared with the same period in 2013, for non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment; and
- Increased operating income of approximately $1.9 million for the three month period ended March 31, 2014 when compared with the same period in 2013, due to lower operating and maintenance costs driven by decreased outside contract labor costs.

Derivative Transactions and Hedging Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as “Operating revenue” and “Cost of natural gas and natural gas liquids”.

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net changes in fair value associated with our derivative financial instruments:

	For the three month period ended March 31,	
	2014	**2013**
	(unaudited; in millions)	
Gathering, Processing and Transportation segment		
Hedge ineffectiveness	$ 1.7	$ 0.5
Non-qualified hedges	(1.4)	0.9
Logistics and Marketing segment		
Non-qualified hedges	4.3	(2.9)
Derivative fair value net gains (losses)	$ 4.6	$(1.5)

RESULTS OF OPERATIONS—BY SEGMENT

Gathering, Processing and Transportation

The following tables set forth the operating results of our Gathering, Processing and Transportation segment and approximate average daily volumes of natural gas throughput and NGLs produced on our major systems for the periods presented:

	For the three month period ended March 31,	
	2014	**2013**
	(unaudited; in millions)	
Operating revenues	$ 203.3	$ 172.2
Cost of natural gas and natural gas liquids	84.8	17.4
Segment gross margin	118.5	154.8
Operating and maintenance	64.4	64.2
General and administrative	24.0	21.9
Depreciation and amortization	35.0	33.5
Operating expenses	123.4	119.6
Operating income (loss)	(4.9)	35.2
Other income (expense)	(1.2)	—
Net income (loss)	$ (6.1)	$ 35.2
Operating Statistics (MMBtu/d)		
East Texas	971,000	1,252,000
Anadarko	824,000	964,000
North Texas	272,000	332,000
Total	2,067,000	2,548,000
NGL Production (Bpd)	82,171	88,498

Three month period ended March 31, 2014 compared with three month period ended March 31, 2013

The operating income of our Gathering, Processing and Transportation segment for the three month period ended March 31, 2014 decreased $40.1 million, as compared with the same period in 2013. The most significant area affected was segment gross margin, which decreased $36.3 million for the three month period ended March 31, 2014, as compared with the same period in 2013.

The segment gross margin for our Gathering, Processing and Transportation segment was affected by the reduced production volumes which negatively affected segment gross margin by approximately $21.0 million for the three month period ended March 31, 2014 compared to the same period in 2013. The average daily volumes of our major systems for the three month period ended March 31, 2014 decreased by approximately 481,000 MMBtu/d, or 19%, when compared to the same period in 2013. The average NGL production for the three month period ended March 31, 2014 decreased by approximately 6,327 Bpd, or 7%, when compared to the same period in 2013. These decreases in volumes on our major systems were primarily attributable to reduced drilling activity by certain producers in the Anadarko region, the loss of a major customer, reduced dry gas drilling, and delayed drilling activity and well completions in East Texas.

A variable element of the operating results of our Gathering, Processing and Transportation segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to the barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the three month period ended March 31, 2014 decreased $7.5 million from the same period in 2013. Within the decline in keep-whole earnings is the result of a decrease in total NGL production primarily due to the Avinger plant shutdown. The Avinger plant was shut down from early January until mid-February of 2014, which we estimate caused an unfavorable segment gross margin impact of $1.4 million for the three month period ended March 31, 2014.

In addition, our Anadarko and North Texas systems experienced sustained freezing temperatures during the first quarter, which reduced wellhead volumes by approximately 50,000 MMBtu/d for the three month period ended March 31, 2014, as compared with the same period in 2013. These sustained freezing temperatures caused our producers to have to shut down some of their production for a period of time due to frozen equipment or other logistical issues, including support vehicles and personnel being unable to access their wells. In addition, the sustained freezing temperatures caused similar logistical issues at our facilities. We estimate that the impact of the sustained freezing temperatures reduced our segment gross margin by approximately $3.0 million in the first quarter of 2014 compared with the same period in 2013. This weather, combined with reduced volumes of approximately 85,000 MMBtu/d due to the loss of a large customer on our Anadarko system, reduced segment gross margin in the first quarter of 2014 compared with the same period in 2013.

The natural gas and NGL production volume outlook on our systems is expected to improve as we progress through 2014. We expect producer drilling plans to accelerate in each of our asset regions later in the year. Additionally, drilling activity by natural gas producers in all regions is targeting rich gas and oil prospects. This is notable in East Texas where existing processing capacity is full despite declining gas volumes. Completion of the Beckville Cryogenic Processing Plant, which is expected to commence service in early 2015, is expected to alleviate this capacity constraint. The Partnership continues to evaluate modifications to existing facilities in East Texas and North Texas to address this trend.

The segment gross margin for our Gathering, Processing and Transportation segment was affected by the reduction in segment gross margin derived from purchasing some of our NGLs at the Conway market hub and selling them at the Mont Belvieu market hub. On our Anadarko system, we purchase certain NGL components at Conway hub prices and then have the option to resell those same NGL components at Mont Belvieu hub prices. For the three months ended March 31, 2014, the prevailing price for NGLs increased approximately 17% per composite barrel at the Mont Belvieu pricing hub, while increasing approximately 23% per composite barrel at the Conway pricing hub, in each case as compared with the prevailing composite barrel prices for the same period in 2013. The price increase per composite barrel at the Conway pricing hub was driven by the sustained freezing temperatures in the Midwest. The segment gross margin of our Gathering, Processing and Transportation segment decreased by approximately $1.4 million for the three months ended March 31, 2014 compared with the same period in 2013, due to the changes in NGL prices between these pricing hubs.

Additionally, the operating results of our Gathering, Processing and Transportation segment experienced a decrease in unrealized, non-cash, mark-to-market net gains of $1.1 million for the three month period ended March 31, 2014 compared to the same period of 2013, primarily related to gains on our equity gas hedges and hedge ineffectiveness. These gains were partially offset by losses on fractionating hedges.

We are exposed to fluctuations in commodity prices in the near term on approximately 40% of the physical natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our segment gross margin generally increases when the prices of these commodities are rising and generally decreases when the prices are declining.

The operating and maintenance costs of our Gathering, Processing and Transportation segment remained relatively flat for the three month period ended March 31, 2014 compared to the same period in 2013.

The general and administrative costs of our Gathering, Processing and Transportation segment for the three month period ended March 31, 2014 slightly increased by $2.1 million compared with the same period in 2013, due primarily to increased workforce related costs.

Depreciation and amortization expense of our Gathering, Processing and Transportation segment increased $1.5 million for the three month period ended March 31, 2014 compared with the same period of 2013, due to additional assets that were put in service.

We recognized a $1.3 million equity loss in "Other income (expense)" on our consolidated statement of income related to our investment in the Texas Express NGL system, which commenced startup operations during the fourth quarter of 2013. This loss is primarily due to deferred make-up rights. The Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. For the three month period ended March 31, 2014, the deferred revenue on the ship or pay contracts amounted to $2.1 million.

In addition, we received approximately $1.6 million in distributions from the Texas Express NGL system joint venture in the three month period ended March 31, 2014.

Future Prospects for Gathering, Processing and Transportation

We have completed several expansion projects and are currently constructing one major expansion project that is designed to increase natural gas processing, NGL production, residue gas and NGL transportation capacity.

Beckville Cryogenic Processing Plant

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville processing plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. We estimate the cost of constructing the plant to be approximately $145 million and expect it to commence service in early 2015. The project is funded by the Partnership and EEP based on their proportionate ownership percentages in Midcoast Operating, which is currently 39% and 61%, respectively.

Logistics and Marketing

The following table sets forth the operating results of our Logistics and Marketing segment for the periods presented:

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Operating revenues	$1,443.6	$1,198.1
Cost of natural gas and natural gas liquids	1,403.9	1,178.7
Segment gross margin	39.7	19.4
Operating and maintenance	17.3	19.2
General and administrative	3.2	2.6
Depreciation and amortization	2.0	1.7
Operating expenses	22.5	23.5
Operating income (loss)	$ 17.2	$ (4.1)

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business. We purchase and receive natural gas, NGLs and other products from pipeline systems and processing plants and sell and deliver them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants. Our Logistics and Marketing segment derives a majority of its operating income from selling natural gas and NGLs received from producers on our Gathering, Processing and Transportation segment pipeline assets to customers utilizing the natural gas. A majority of the natural gas and NGLs we purchase are produced in Texas markets where we have expanded access to several interstate natural gas pipelines over the past several years, which we can use to transport natural gas to primary markets where it can be sold to major natural gas customers. Additionally, our Logistics and Marketing segment derives operating income from providing logistics services for our customers from the wellhead to markets.

Three month period ended March 31, 2014 compared with three month period ended March 31, 2013

The operating income of our Logistics and Marketing segment for the three month period ended March 31, 2014 increased $21.3 million, as compared with the same period in 2013. The most significant area affected was segment gross margin which increased $20.3 million for the three month period ended March 31, 2014, as compared with the same period in 2013.

Our segment gross margin was primarily impacted by increased margins within our gas marketing function which benefited from price differentials between market centers by approximately $10.0 million for the three month period ended March 31, 2014, when compared to the same period of 2013. We benefited on the difference between market centers in the Mid-Continent supply areas and market area in the Midwest which arose due to higher than usual demand from winter weather in the Midwest. We achieved these higher margins due to firm transportation we hold on certain third party pipelines which fixed the rate we pay for transportation at a cost less than the differences between market centers which occurred in the first quarter of 2013.

The operating results of our Logistics and Marketing segment experienced an increase in unrealized, non-cash, mark-to-market net gains of $7.2 million for the three month period ended March 31, 2014 compared to the same period of 2013, primarily from the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs and the natural gas stream resulting from the operating activities of our Logistics and Marketing segment.

Operating and maintenance costs of our Logistics and Marketing segment were $1.9 million lower for the three month period ended March 31, 2014 compared with the three month period ended March 31, 2013, due to reduced outside contract labor costs.

General and administrative costs of our Logistics and Marketing segment were relatively flat for the three month period ended March 31, 2014 when compared with the three month period ended March 31, 2013.

Depreciation and amortization expense for the three month period ended March 31, 2014 was also relatively flat when compared with the three month period ended March 31, 2013.

Corporate

Our corporate activities consist of interest expense, interest income and other costs such as income taxes, which are not allocated to the business segments.

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Interest expense, net	$ 3.3	$—
Other income (expense)	(0.1)	0.1
Income tax expense	1.0	0.5
Net loss	(4.4)	(0.4)
Net loss attributable to noncontrolling interests	6.3	—
Net loss attributable to general and limited partners	$(10.7)	$(0.4)

Our interest cost for the three month periods ended March 31, 2014 and 2013 is comprised of the following:

	For the three month period ended March 31,	
	2014	2013 (1)
	(unaudited; in millions)	
Interest cost incurred	$ 3.3	$ 5.6
Interest capitalized	—	5.6
Interest expense, net	$ 3.3	$—
Interest cost paid	$ 2.8	$ 5.6
Weighted average interest rate (2)	2.1%	—

(1) Prior to the Offering, the interest cost we recognized was an allocation of EEP's cost. In connection with the closing of the Offering, the Partnership, Midcoast Operating, and their material domestic subsidiaries, entered into the Credit Agreement to establish their own committed senior revolving credit facility.

(2) At March 31, 2013, MEP had no outstanding debt and no weighted average interest rate.

Three month period ended March 31, 2014 compared with three month period ended March 31, 2013

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income are typically borne by our unitholders through the allocation of taxable income.

The tax structure that exists in Texas imposes taxes that are based upon many, but not all, items included in net income. Our income tax expense of $1.0 million for the three month period ended March 31, 2014, is computed by applying a 0.5% Texas state income tax rate to modified gross margin, as defined by Texas state income tax laws, as discussed in Note 12. *Income Taxes*. For the three month period ended March 31, 2013, we had income tax expense of $0.5 million, which we computed by applying a 0.5% Texas state income tax rate to modified gross margin.

LIQUIDITY AND CAPITAL RESOURCES

Historically, our sources of liquidity included cash generated from operations and funding from EEP. We were dependent upon EEP and its affiliates for our treasury services. We now have separate bank accounts from EEP, but EEP provides treasury services on our General Partner's behalf under an intercorporate services agreement that we entered into with EEP at the closing of the Offering. Under the intercorporate services agreement, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would be fully allocable to Midcoast Operating by $25.0 million annually. In addition, at the close of the

Offering, Midcoast Operating entered into a Financial Support Agreement, which we refer to as the Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP will, from time to time, provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party.

We expect our ongoing sources of liquidity to include cash generated from operations of Midcoast Operating, borrowings under Midcoast Operating's working capital credit facility, borrowings under our revolving credit facility and issuances of additional debt and equity securities. We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements and long-term capital expenditure requirements and to make quarterly cash distributions to our unitholders.

Credit Facility

On November 13, 2013, in connection with the closing of the Offering, we, Midcoast Operating, and our material domestic subsidiaries, entered into a Credit Agreement, which we refer to as the Credit Agreement, by and among us, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, the material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially (1) $90.0 million under the letter of credit facility and (2) $75.0 million under the swing line facility. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility matures in three years, subject to four one-year requests for extensions. At March 31, 2014, we were in compliance with the terms of our financial covenants.

Loans under the Credit Agreement accrue interest at a per annum rate by reference, at our election, to the Eurodollar rate, which is equal to the LIBOR rate or a comparable or successor rate reasonably approved by the Administrative Agent, or base rate, in each case, plus an applicable margin. The applicable margin on Eurodollar (LIBOR) rate loans ranges from 1.75% to 2.75% and the applicable margin on base rate loans ranges from 0.75% to 1.75%, in each case determined based upon our total leverage ratio (as defined below) at the applicable time. At March 31, 2014, we had $250.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, MEP had net repayments of approximately $85.0 million during the three month period ended March 31, 2014, which includes gross borrowings of $1,725.0 million and gross repayments of $1,810.0 million. A letter of credit fee is payable by the borrowers equal to the applicable margin for Eurodollar (LIBOR) rate loans times the daily amount available to be drawn under outstanding letters of credit. A commitment fee is payable by us equal to an applicable margin times the daily unused amount of the lenders' commitment, which applicable margin ranges from 0.30% to 0.50% based upon our total leverage ratio at the applicable time.

Each of our domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The Credit Agreement is unsecured but security will be provided upon occurrence of any of the following: (1) for two consecutive quarters, the Total Leverage Ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (2) uncured breach to certain terms and conditions of the Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

Additionally, the Credit Agreement contains various covenants and restrictive provisions which limit our ability and that of, Midcoast Operating and their subsidiaries to incur certain liens or permit them to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests during the continuance of a default, incur or guarantee additional debt, repay subordinated debt prior to maturity, make certain investments and acquisitions, alter their lines of business, enter into certain types of transactions with affiliates and enter into agreements that restrict their ability to perform certain obligations under the Credit Agreement or to make payments to a borrower or any of their material subsidiaries.

The Credit Agreement also requires compliance with two financial covenants. We are not permitted to allow our ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. We also must maintain (on a consolidated basis), as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00.

These covenants are subject to exceptions and qualifications set forth in the Credit Agreement. At such time as we obtain an investment grade rating from either Moody's or S&P, certain covenants under the Credit Agreement will no longer be applicable to either the borrowers or the guarantors, or in some instances, any of them (including, but not limited to, the obligation to provide security in certain circumstances, certain restrictions on liens, investments and debt, and restrictions on dispositions).

At March 31, 2014, we could borrow approximately $850.0 million under the terms of our Credit Agreement and working capital credit facility, determined as follows:

	(in millions)
Total credit available under Credit Agreement	$850.0
Total credit available under working capital credit facility	250.0
Less: Amounts outstanding under Credit Agreement	250.0
Total amount we could borrow at March 31, 2014	$850.0

Working Capital Credit Facility

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a $250.0 million working capital credit facility with EEP as the lender. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility are scheduled to mature on November 13, 2017, and accrue interest at a per annum rate of the London Interbank Offered Rate, or LIBOR, plus 2.5%. EEP's commitment to lend pursuant to the working capital credit facility will end on the earlier of the facility's maturity date (by acceleration or otherwise) and the date on which EEP owns less than 20% of the outstanding limited partner interests in Midcoast Operating. If EEP's commitment to lend has terminated before the facility has matured (by acceleration or otherwise), then the aggregate amount of all outstanding borrowings under the facility will automatically convert to a term loan that will bear interest at LIBOR (calculated as of the conversion date) plus 2.5%. Midcoast Operating has agreed to pay a commitment fee on the unused commitment at a per annum rate of 0.4250%, payable each fiscal quarter.

The working capital credit facility contains customary events of default, including (1) the failure of Midcoast Operating to make payments required under the working capital credit facility or comply with the conditions of such working capital credit facility; (2) the failure of any of the representations or warranties of Midcoast Operating to be true in all material respects when made; (3) the occurrence of a change of control; (4) the institution of insolvency or similar proceedings against Midcoast Operating or us; and (5) the occurrence of a default under any other material indebtedness of Midcoast Operating or us. During the existence of an event of default, subject to the terms and conditions of the working capital credit facility, EEP may terminate its commitment and may declare any outstanding principal, together with accrued and unpaid interest, to be immediately due and payable. The working capital credit facility also contains certain customary representations, warranties, indemnities and remedies provisions and also provides that, if the Credit Agreement is secured, the working capital credit facility also will be secured to the same extent on a second lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the working capital credit facility and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Financial Support Agreement

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP has agreed to provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party. Under the Financial Support Agreement, EEP's support of Midcoast Operating's and its wholly owned subsidiaries' obligations will terminate on the earlier to occur of (1) the fourth anniversary of the closing of the Offering and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in the Partnership), less than 20% of the total outstanding limited partner interest in Midcoast Operating.

The annual costs that Midcoast Operating initially estimates that it will incur under the Financial Support Agreement range from approximately $4.0 million to $5.0 million and are based on the cumulative average amount of letters of credit and guarantees that EEP will provide on Midcoast Operating's and its wholly owned subsidiaries' behalf multiplied by a 2.5% annual fee. The cumulative average amount of letters of credit and guarantees will be calculated (1) with respect to letters of credit, by reference to the aggregate face value, in U.S. dollars, of letters of credit outstanding at the close of business on any business day, after taking into account any changes in such amount since the close of business on the immediately preceding business day, and (2) with respect to guarantees, by reference to the net realizable financial obligation of Midcoast Operating and its wholly owned subsidiaries under the applicable contracts, in each case after taking into account market fluctuations in commodity prices, any related EEP letters of credit and any increases or decreases underlying each guarantee. The "net realizable financial obligation" is (1) in the case of outstanding commodity derivative contracts, the amount required to terminate or discharge each such contract based upon current market prices of the relevant commodity and (2) in the case of natural gas and NGL purchase agreements, the outstanding amount owed for product received that would be recorded as a liability under U.S. GAAP, in each case, net of any amounts owed to Midcoast Operating under any agreements with counterparties that have received guarantees from EEP. Based on the Partnership's 39% controlling interest in Midcoast Operating, the Partnership incurred $1.2 million of these annual costs for the three months ending March 31, 2014, which is included in "Operating and maintenance" on our consolidated statements of income.

The Financial Support Agreement also provides that if the Credit Agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the Financial Support Agreement and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Available Liquidity

Our primary sources of liquidity are provided by the Credit Agreement and our working capital facility. As set forth in the following table, we had approximately $963.0 million of liquidity available to us at March 31, 2014, to meet our ongoing operational, investment and financing needs.

	(in millions)
Cash and cash equivalents	$113.0
Total credit available under Credit Agreement	850.0
Total credit available under working capital credit facility	250.0
Less: Amounts outstanding under Credit Agreement	250.0
Total	$963.0

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013 and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of those of our subsidiaries and other subsidiaries of EEP that are parties thereto up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement. EEP and, as of December 2, 2013, MEP, each act in an administrative capacity as collection agent on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. EEP and MEP have no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in “General and administrative—affiliate” expense in our consolidated statements of income. For the three month period ended March 31, 2014, the loss stemming from the discount on the receivables sold was $0.3 million. For the three period ended March 31, 2014, we derecognized and sold $976.3 million of accrued receivables to the Enbridge subsidiary. For the three month period ended March 31, 2014, the cash proceeds were $976.0 million which was remitted to the buyer through our centralized treasury system. As of March 31, 2014, $322.4 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of March 31, 2014, we have $14.0 million included in “Restricted cash” on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary.

Cash Requirements

Capital Spending

We categorize our capital expenditures as either maintenance or expansion capital expenditures. Maintenance capital expenditures are cash expenditures that are made to maintain our asset base, operating capacity or operating income or to maintain the existing useful life of any of our capital assets, in each case over the long term. Examples of maintenance capital expenditures include expenditures to replace pipelines or processing facilities, to maintain equipment reliability, integrity and safety or to comply with existing governmental regulations and industry standards. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as maintenance capital expenditures. We expect to incur continuing annual maintenance capital expenditures primarily for well-connects and for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital expenditures will increase due to the growth of our pipeline systems. We expect to fund our proportional share of maintenance capital expenditures through operating cash flows.

Expansion capital expenditures are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our asset base, operating capacity or operating income over the long term or meaningfully extend the useful life of any of our capital assets. Examples of expansion capital expenditures include the acquisition of additional assets or businesses, as well as capital projects that improve the service capability of our existing assets, increase operating capacities or revenues, reduce operating costs from existing levels or enable us to comply with new governmental regulations or industry standards. We anticipate funding our proportional share of expansion capital expenditures temporarily through borrowings under our revolving credit facility, with long-term debt and equity funding being obtained when needed and as market conditions allow.

If EEP elects not to fund any capital expenditures at Midcoast Operating, we will have the option to fund all or a portion of EEP's proportionate share of such capital expenditures in exchange for additional interests in Midcoast Operating. As a result, if our interests in Midcoast Operating increase, our proportionate share of the capital expenditures incurred by Midcoast Operating will also increase proportionate to our interest in Midcoast Operating. To the extent that EEP elects not to fund all or a portion of its proportionate share of Midcoast Operating's capital expenditures, and we elect not to fund any capital expenditures not funded by EEP, we expect that Midcoast Operating will not pursue the applicable capital projects associated with such unfunded capital expenditures.

At March 31, 2014, we had approximately $93.8 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2014. The following table sets forth our estimated maintenance and expansion capital expenditures of $150.0 million for the year ending December 31, 2014. Although we anticipate making these expenditures in 2014, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. As of March 31, 2014, we have recognized approximately $62.7 million in capital expenditures, including $13.3 million on maintenance capital activities. For the year ending December 31, 2014, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
Beckville Cryogenic Processing Plant	$110
Wellconnect Expansion Capital	55
Texas Express NGL system	20
Expansion Capital [1]	140
Maintenance Capital Expenditure Activities	65
Less joint funding from:	
EEP [2]	240
	$150

[1] Includes new compression, growth opportunities as well as other enhancements.

[2] Joint funding is based upon EEP's current 61% ownership of Midcoast Operating.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at March 31, 2014 for each of the indicated calendar years:

	Notional	2014	2015	2016	2017	2018	Total
			(in millions)				
Swaps							
Natural gas [1]	51,973,300	$(0.7)	$—	$—	$—	$—	$(0.7)
NGL [2]	3,187,000	(3.5)	0.3	—	—	—	(3.2)
Crude Oil [2]	1,391,900	(5.3)	1.1	0.7	—	—	(3.5)
Options							
Natural gas—puts purchased [1]	7,315,000	0.4	1.9	—	—	—	2.3
Natural gas—puts written [1]	1,729,000	(0.2)	—	—	—	—	(0.2)
Natural gas—calls written [1]	1,277,500	—	(0.4)	—	—	—	(0.4)
NGL—puts purchased [2]	1,507,750	2.3	6.1	—	—	—	8.4
NGL—calls purchased [2]	46,000	0.2	—	—	—	—	0.2
NGL—calls written [2]	498,250	(0.6)	(1.6)	—	—	—	(2.2)
Crude Oil—puts purchased [2]	547,750	—	2.3	0.6	—	—	2.9
Crude Oil—calls written [2]	547,750	—	(3.1)	(0.7)	—	—	(3.8)
Forward contracts							
Natural gas [1]	212,421,945	1.4	0.8	0.2	(0.1)	—	2.3
NGL [2]	11,163,299	2.1	0.4	—	—	—	2.5
Crude Oil [2]	1,420,428	(1.1)	—	—	—	—	(1.1)
Totals		$(5.0)	$ 7.8	$ 0.8	$(0.1)	$—	$ 3.5

(1) Notional amounts for natural gas are recorded in Millions of British Thermal Units, or MMBtu.
(2) Notional amounts for NGLs and crude oil are recorded in Barrels, or Bbl.

Cash Flow Analysis

The following table summarizes the changes in cash flows by operating, investing and financing for each of the periods indicated:

	For the three month period ended March 31, 2014	2013	Variance 2014 vs. 2013 Increase (Decrease)
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$213.8	$ 109.3	$104.5
Investing activities	(15.3)	(111.8)	96.5
Financing activities	(90.4)	2.5	(92.9)
Net increase in cash and cash equivalents	108.1	—	108.1
Cash and cash equivalents at beginning of year	4.9	—	4.9
Cash and cash equivalents at end of period	$113.0	$ —	$113.0

Operating Activities

Net cash provided by our operating activities increased $104.5 million for the three month period ended March 31, 2014 compared to the same period in 2013, primarily due to an increase in our working capital accounts of $126.0 million. This increase due to our working capital accounts was partially offset by a $24.0 million decrease in net income, offset by other non-cash items. The $0.9 million increase in our non-cash items primarily consists of a $6.1 million increase in derivative net gains, compared to net losses in 2013, as a result of fluctuations in commodity prices and volumes. Offsetting this non-cash item were:

- Decreased allowance for interest during construction of $2.8 million attributable to the Texas Express NGL system that went into service in late 2013; and
- Increased depreciation expense $1.8 million in 2014 due to the Texas Express NGL system going into service at the end of 2013.

Changes in our working capital accounts are shown in the following table and discussed below:

	For the three month period ended March 31,		Variance
	2014	2013	2014 vs. 2013
	(unaudited; in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 3.5	$ (42.8)	$ 46.3
Due from General Partner and affiliates	616.3	7.5	608.8
Accrued receivables	59.2	133.3	(74.1)
Inventory	26.2	(2.9)	29.1
Current and long-term other assets	(4.8)	(1.7)	(3.1)
Due to General Partner and affiliates	(478.3)	16.5	(494.8)
Accounts payable and other	(42.5)	(22.6)	(19.9)
Environmental liabilities	0.2	—	0.2
Accrued purchases	(2.4)	(37.1)	34.7
Interest payable	0.5	—	0.5
Property and other taxes payable	(8.6)	(6.9)	(1.7)
Net change in working capital accounts	$ 169.3	$ 43.3	$ 126.0

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the three month period ended March 31, 2014, compared to the same period in 2013, is primarily the result of general timing differences for cash receipts and payments associated with current accounts. Other items affecting our cash flows from operating assets and liabilities include the following:

- The changes in the balances of due to and due from General Partner and affiliates are primarily attributable to transition of cash management functions from EEP to MEP following the Offering at the end of 2013. EEP provided us with interim cash management services following the Offering to facilitate the collection of and payment on our accounts, which resulted in increase in amounts receivable from and payable to EEP as of December 31, 2013. As of March 31, 2014, we had completed this transition and settled most of the transactions causing a decrease in both our due to and due from General Partner and affiliates account. These transactions were not present during the three month period ended March 31, 2013;
- The change in accrued receivables was unfavorable due to lower prices and volumes of NGLs partially offset by increased prices and volumes of natural gas from the three month period ended March 31, 2014, compared to the same period in 2013. In addition, any sales of receivables due to our Receivables Agreement offset any activity in the accrued receivables balance. For more information, refer to the discussion above *Sale of Accounts Receivable.* Similar sales of receivables did not occur for the three month period ended March 31, 2013;

- The change in trade receivables for the three month period ended March 31, 2014 was favorable due to our sale of receivables based on our Receivables Agreement. For more information, refer to the discussion above *Sale of Accounts Receivable*. These favorable events were partially offset by increased collections outstanding from our sale of receivables in 2014. Similar sales of receivables did not occur for the three month period ended March 31, 2013; and

- The decline in accrued purchases from December 31, 2012 to March 31, 2013 was primarily due to plant issues in South Texas where our trucking and NGL marking business trucks were experiencing longer wait times where they were not able to unload their product and pick up product efficiently due to the plants being full. This decrease was partially offset by increased transportation and fractionation accruals for the three month period ended March 31, 2013. There were no such delays in the same period in 2014.

Investing Activities

Net cash used in our investing activities during the three month period ended March 31, 2014 decreased by $96.5 million, compared to the same period in 2013, primarily due to:

- Decreased restricted cash balance of $47.5 million consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary in accordance with the Receivables Agreement. For more information, refer to discussion above *Sale of Accounts Receivable*;
- Decreased contributions to fund the construction activities associated with the Texas Express NGL system of approximately $29.5 million since the system went into service in late 2013; and
- Decreased additions to property, plant and equipment, net of construction payables of $22.5 million when compared with 2013, due to many of our capital projects being put into service in 2013 with less capital projects projected for the future.

Financing Activities

Net cash used in our financing activities increased $92.9 million for the three month period ended March 31, 2014, compared to the same period in 2013, due to:

- Net repayments of $85.0 million for amounts previously outstanding under our credit facility in 2014 while we had no debt activity during 2013; and
- Decreased contributions from partners of $23.5 million partially offset by decreased distributions to partners of $15.6 million.

SUBSEQUENT EVENTS

Distribution to Partners

On April 29, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to our partners on May 15, 2014. The distribution will be paid to unitholders of record as of May 8, 2014, of our available cash of $14.4 million at March 31, 2014, or $0.3125 per limited partner unit. We will pay $6.6 million to our public Class A common unitholders, while $7.8 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On April 29, 2014, the general partner of Midcoast Operating, acting in its capacity as the general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of May 8, 2014. Midcoast Operating will pay $15.3 million to us and $23.9 million to EEP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on 10-K for the fiscal year ended December 31, 2013 filed on February 18, 2014, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2014 and December 31, 2013.

	At March 31, 2014						At December 31, 2013	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
						(in millions)		
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	872,000	$ 4.43	$ 4.28	$ 0.1	$—	$—	$ —
	NGL	653,750	$ 65.16	$ 65.99	$ 0.9	$(1.5)	$ 0.6	$ (0.4)
	Crude Oil	70,000	$100.82	$100.10	$ 0.1	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	2,443,800	$ 4.00	$ 4.39	$—	$(1.0)	$ 0.1	$ (1.0)
	NGL	1,967,500	$ 54.50	$ 56.00	$ 4.8	$(7.7)	$ 4.8	$(12.7)
	Crude Oil	858,250	$ 91.82	$ 98.09	$ 0.2	$(5.6)	$ 0.3	$ (5.4)
Receive variable/pay variable	Natural Gas	38,490,000	$ 4.38	$ 4.38	$ 0.6	$(0.4)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	5,703,122	$ 4.46	$ 4.41	$ 0.4	$(0.1)	$—	$ —
	NGL	1,073,640	$ 57.57	$ 57.25	$ 1.2	$(0.9)	$ 0.9	$ (0.9)
	Crude Oil	243,713	$ 99.24	$ 99.81	$ 0.3	$(0.4)	$—	$ —
Receive fixed/pay variable	Natural Gas	23,485,419	$ 4.33	$ 4.33	$ 0.1	$(0.1)	$—	$ —
	NGL	1,197,064	$ 55.26	$ 56.68	$ 0.1	$(1.8)	$ 0.4	$ (2.6)
	Crude Oil	333,526	$ 99.25	$100.28	$ 0.4	$(0.7)	$—	$ (0.4)
Receive variable/pay variable	Natural Gas	89,130,497	$ 4.41	$ 4.40	$ 1.8	$(0.7)	$ 0.9	$ (0.4)
	NGL	8,029,834	$ 42.91	$ 42.48	$ 5.2	$(1.7)	$ 5.8	$ (3.7)
	Crude Oil	843,189	$ 97.13	$ 98.03	$ 3.4	$(4.1)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Natural Gas	60,000	$ 4.52	$ 4.51	$—	$—	$—	$ —
	NGL	565,750	$ 51.33	$ 50.71	$ 1.4	$(1.1)	$ 1.5	$ (1.1)
	Crude Oil	350,400	$ 93.00	$ 89.89	$ 1.2	$(0.2)	$ 1.7	$ —
Receive variable/pay variable	Natural Gas	10,107,500	$ 4.32	$ 4.33	$ 0.1	$(0.1)	$ 0.1	$ —
Receive variable/pay fixed	Crude Oil	67,500	$ 92.58	$ 91.10	$ 0.1	$—	$—	$ —
Physical Contracts								
Receive fixed/pay variable	Natural Gas	3,158,951	$ 4.49	$ 4.50	$—	$—	$—	$ —
	NGL	54,760	$ 54.21	$ 52.91	$ 0.1	$—	$—	$ —
Receive variable/pay variable	Natural Gas	46,325,708	$ 4.24	$ 4.22	$ 1.2	$(0.4)	$ 0.5	$ (0.1)
	NGL	808,001	$ 71.16	$ 70.79	$ 0.4	$(0.1)	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 84.52	$ 0.7	$—	$ 0.7	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	31,192,423	$ 3.97	$ 3.97	$ 0.7	$(0.5)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	13,425,825	$ 4.17	$ 4.18	$ 0.3	$(0.4)	$—	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.
(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.
(3) The fair value is determined based on quoted market prices at March 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of gains at December 31, 2013.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at March 31, 2014 and December 31, 2013.

	At March 31, 2014						At December 31, 2013	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
					(in millions)			
Portion of option contracts maturing in 2014								
Puts (purchased)	Natural Gas	3,300,000	$ 3.90	$ 4.46	$ 0.4	$—	$ 0.7	$—
	NGL	394,500	$53.04	$53.17	$ 2.3	$—	$ 2.9	$—
Calls (written)	NGL	206,250	$59.62	$54.36	$—	$(0.6)	$—	$(1.0)
Puts (written)	Natural Gas	1,729,000	$ 3.90	$ 4.49	$—	$(0.2)	$—	$(0.5)
Calls (purchased)	NGL	46,000	$50.40	$45.73	$ 0.2	$—	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.20	$ 1.9	$—	$ 1.7	$—
	NGL	1,113,250	$50.64	$53.31	$ 6.1	$—	$ 6.0	$—
	Crude Oil	456,250	$85.00	$89.50	$ 2.3	$—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.20	$—	$(0.4)	$—	$(0.3)
	NGL	292,000	$62.48	$57.59	$—	$(1.6)	$—	$(1.0)
	Crude Oil	456,250	$90.70	$89.50	$—	$(3.1)	$—	$(1.9)
Portion of option contracts maturing in 2016								
Puts (purchased)	Crude Oil	91,500	$80.00	$84.30	$ 0.6	$—	$—	$—
Calls (written)	Crude Oil	91,500	$87.00	$84.30	$—	$(0.7)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at March 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

	March 31, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$—	$ 0.2
AA	(0.5)	(2.1)
A	2.0	(1.1)
Lower than A	2.0	1.6
	$ 3.5	$(1.4)

(1) As determined by nationally-recognized statistical ratings organizations.

Item 4. Controls and Procedures

We, EEP and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, or the Exchange Act, within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of March 31, 2014. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended March 31, 2014.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, "Note 10. *Commitments and Contingencies*," which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, filed with the SEC on February 18, 2014.

Item 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

MIDCOAST ENERGY PARTNERS, L.P.
(Registrant)

By: Midcoast Holdings, L.L.C.
as General Partner

Date: May 1, 2014 By: /s/ C. Gregory Harper

C. Gregory Harper
Principal Executive Officer

Date: May 1, 2014 By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as a part of this Quarterly Report on Form 10-Q. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated.

Exhibit Number	Description
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, C. Gregory Harper, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Midcoast Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

By: /s/ C. Gregory Harper

C. Gregory Harper
Principal Executive Officer
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Neyland, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Midcoast Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Executive Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014 (the “Quarterly Report”) filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: May 1, 2014

By: /s/ C. Gregory Harper

C. Gregory Harper
Principal Executive Officer
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Financial Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014 (the "Quarterly Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: May 1, 2014

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President —Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)